UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Pacific Gas and Electric Company — Docket Nos. ER03-409-000 and EL05-35-000

OPINION NO. 482

OPINION AND ORDER ON INITIAL DECISION

Issued: October 24, 2005

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Pacific Gas and Electric Company Docket Nos. ER03-409-000 and EL05-35-000

OPINION NO. 482

APPEARANCES

*Lisa Wolfe, Esq. and Sidney Mannheim, Esq.* on behalf of California Electricity Oversight Board.

*Donald Brookhyser, Esq.* on behalf of Cogeneration Association of California and the Energy Producers and Users Coalition.

*Mark D. Patrizio, Esq., Steve Metague, Esq., Stuart K. Gardiner, Esq. and Chad D. Naylor, Esq.* on behalf of Pacific Gas and Electric Company.

*Jennifer L. Key, Esq.* on behalf of Southern California Edison Company.

*Nicholas Sher, Esq., Arocles Aguilar, Esq., Todd O. Edmister, Esq., and Jonathan Bromson, Esq.* on behalf of California Public Utilities Commission.

*Harvey L. Reiter, Esq., Glen L. Ortman, Esq., Adrienne E. Clair, Esq., Arlen Orchard, Esq., Laura Lewis, Esq., and Andrew K. Hughes, Esq.* on behalf of Sacramento Municipal Utility District.

*Andrea G. Lonian, Esq., Lisa Dowden, Esq., Robert McDiarmid, Esq., and Stephen C. Pearson, Esq.* on behalf of Northern California Power Agency.

*Frederick H. Hoover, Jr., Esq., Tamir Ben-Yoseph, Esq., Wallace L. Duncan, Esq., James D. Pembroke, Esq., Michael R. Postar, Esq., Lisa S. Gast, Esq., Derek A. Dyson, Esq., Peter J. Scanlon, Esq. and Sean M. Neal, Esq.* on behalf of Transmission Agency of Northern California.

*Wallace L. Duncan, Esq., Sean M. Neal, Esq., and Derek A. Dyson* on behalf of Modesto Irrigation District.

*Wallace L. Duncan, Esq., Michael R. Postar, Esq., and Diana Mahmud, Esq.* on behalf of State Water Contractors and Metropolitan Water District of Southern California.

*Elisa J. Grammer, Esq. and Edna Walz, Esq.* on behalf of State Water Project, California Department of Water Resources.

*Michael N. McCarty, Esq., and Michael K. Lavanga, Esq.* on behalf of Merced Irrigation District.

*Bradley R. Miliauskas, Esq. and David B. Rubin, Esq.* on behalf of California Independent System Operator Corporation.

*Theresa Mueller, Esq.* on behalf of City and County of San Francisco.

*Jeff Layton, Esq.* on behalf of California Electricity Oversight Board.

*Sean M. Neal, James D. Pembroke, Esq., Lisa S. Gast, Esq. and Peter J. Scanlon, Esq.* on behalf of City of Santa Clara, California, d/b/a Silicon Valley Power; the City of Redding, California; and M-S-R Public Power Agency.

*Helene De Neuville Pangas, Esq.* on behalf of Turlock Irrigation District.

*Howard Benowitz, Esq., Robert B. Gex, Esq., and Marco Gomez, Esq.* on behalf of San Francisco Bay Area Rapid Transit District.

*Jo Ann Scott, Esq., Marcia C. Hooks, Esq. and Cynthia A. Govan, Esq.* on behalf of the Trial Staff of the Federal Energy Regulatory Commission.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Nora Mead Brownell, and Suedeen G. Kelly.

Pacific Gas and Electric Company | Docket Nos. ER03-409-000 and EL05-35-000

OPINION NO. 482

OPINION AND ORDER ON INITIAL DECISION

(Issued October 24, 2005)

1. On February 9, 2005, the Presiding Administrative Law Judge (ALJ) issued an initial decision in this proceeding.[1] This opinion resolves the issue of whether the standby customer rates should be set on the basis of adjusted contract demand using a probabilistic analysis or by the use of the 12 coincident peak methodology. This opinion sets just and reasonable transmission rates for standby customers of Pacific Gas and Electric Company (PG&E).

**Background**

2. On January 13, 2003, in Docket No. ER03-409-000, PG&E filed a proposed change in its transmission rates (TO6 rates) under its Transmission Owner (TO) Tariff. On March 12, 2003, the Commission accepted the TO6 rates for filing, suspended them, and made them effective August 13, 2003, subject to refund, and set them for hearing.[2] In its TO6 filing, PG&E proposed to increase its total annual revenue requirement of \$379 million by \$166 million to a total of \$545 million.[3] As relevant here, PG&E

[1] *Pacific Gas and Electric Co.*, 110 FERC ¶ 63,026 (2005).

[2] *Pacific Gas and Electric Co.*, 102 FERC ¶ 61,270 (2003).

[3] *Id.* at P 3.

proposed to increase the standby reservation charge for the standby customers from $0.26 per Kw of contract capacity to $0.35 per Kw.

3. On December 13, 2004, the Commission consolidated the TO6 proceeding with Docket No. EL05-35-000 for purposes of hearing and decision.[4] Docket No. EL05-35-000 was a subsequent proceeding under section 206 of the Federal Power Act, 16 U.S.C. § 824e (2000), to examine PG&E's allocation of reliability services costs to standby service customers. It was determined that Docket No. EL05-35-000 was inextricably linked to Docket No. ER03-409-000. Hence, the two were consolidated.

4. All issues but one relating to the standby rate in this proceeding have been resolved through hearing procedures and settlements.[5] The remaining unresolved issue is whether PG&E's proposed rate design for rates charged to standby customers is just and reasonable.

**Positions of the Parties**

5. At issue in this proceeding are two competing rate methodologies for computing the allocation of PG&E's transmission costs to the standby transmission customers. The Cogeneration Association of California and the Energy Producers and Users Coalition (collectively, CoGen Associates) propose a 12 coincident peak methodology, which uses the average of the peak use from each month in the test year to allocate demand costs. PG&E adopted the 12 coincident peak methodology for all transmission rates except for its standby transmission rates. For the standby customer class, however, PG&E proposes to allocate transmission costs using a rate design that allocates costs based on a percentage developed using a probabilistic analysis of the total standby customer contract demand.

6. PG&E states that its proposed methodology for assigning costs to the standby customer class in this proceeding is the same as that which was agreed to in the settlement of PG&E's TO5 case.[6] PG&E adds that, for purposes of the TO6 case, updated 12 coincident peak demands and a new test year 2003 sales forecast were

[4] *Pacific Gas and Electric Co.,* 109 FERC ¶ 61,266 at P 21 (2004).

[5] *See, e.g., Pacific Gas and Electric Co.,* Opinion No. 470, 106 FERC ¶ 61,242 (2004); *Pacific Gas and Electric Co.,* 108 FERC ¶ 61,169 (2004).

[6] *Pacific Gas and Electric Co*., 96 FERC ¶ 61,122 (2001).

prepared.[7] PG&E explains that its methodology provides that transmission costs be assigned to the standby customer class using 27.1 percent of the total contract demand for the standby class. The 27.1 percent standby cost allocation factor, PG&E states, was developed as a weighted average of: (1) a 12 percent allocation factor used for the regional transmission share of the total transmission revenue requirement; and (2) a 38 percent allocation factor used for the local transmission share of the total transmission revenue requirement.

7. PG&E argues that its proposed rate design for standby transmission service is reasonable because standby transmission service is different from other classes of service to which PG&E allocates costs based on a 12 coincident peak methodology. PG&E argues that the variations in demand for standby transmission service are different than ordinary variations in load of any other customer class, because standby transmission service is typically associated with unscheduled outages of the customer's generating equipment (which, when it is out of service, necessitates a substantial increase in needed transmission service).

8. PG&E states that it will not charge standby customers based on their full contracted-for amount of service; instead PG&E would adjust the contracted-for amount of service down, based on a probabilistic analysis reflecting the number of customer generators likely to be out of service during the coincident peak hours. PG&E adds that its proposed rate design for standby service is consistent with the requirements of 18 C.F.R. § 292.305(c) (2005) in regard to the rate for sales to qualifying facilities of back-up power or maintenance power.

9. CoGen Associates responds that the standby customer class is no different than other customer classes and does not justify a different rate treatment. CoGen Associates contend that cost causation is the principle by which costs should be allocated and that properly designed rates should produce revenues from each customer class that match the costs to serve each customer class. CoGen Associates argue that the standby customer class causes PG&E to incur costs in the same manner as all other classes. CoGen Associates assert that the standby customer class demand is not unpredictable and an adjustment to the allocation cannot be justified based on unpredictability. CoGen Associates argue that the 12 coincident peak methodology is the appropriate basis on which to allocate costs since PG&E plans its system to meet the system peak demand.

[7] Exh. PGE 45-13

CoGen Associates also argue that PG&E's proposed rate design makes no sense because it is based on demand of the standby class during the summer without regard to system peak.

10. Commission Trial Staff (Trial Staff) supports PG&E's proposal that standby transmission rates should be developed using a probabilistic analysis.

**<u>The Initial Decision</u>**

11. On February 9, 2005, the ALJ issued an initial decision in which she noted that PG&E is obligated to provide standby service, and PG&E's proposed standby customer class rate based on contract demand is not *per se* unreasonable or discriminatory merely because PG&E uses a 12 coincident peak methodology for other rate customer classes.[8] If the standby customer class is not similarly situated to these other customer classes, the ALJ stated, then a rate based on contract demand may be appropriate. The ALJ found that, given the unpredictability of both the timing of outages and the demand of individual members of the standby class, PG&E met its burden of proving that the standby customer class is not similarly situated to PG&E's other customer classes. Further, the ALJ stated that having PG&E standing ready to provide service to standby customers on demand is a valuable service, and rates based on this potential use of power, rather than actual use, are not *per se* unreasonable and may be reasonable if they are based on reasonable extrapolations from historical data on operating demand.[9]

12. However, the ALJ found that PG&E has not met its burden to prove that its particular proposed standby transmission rate design is just and reasonable.[10] The ALJ found that the main problem is with how PG&E generates its 27.1 percent allocation factor.[11] Regarding the regional component of the 27.1 percent allocation factor, the ALJ stated that component was originally developed for allocating generation costs and that no other support was provided to connect it to the current application to the standby customer class; it also is based on a methodology that is more than 10 years old.[12] The

---

[8] *Pacific Gas and Electric Co.,* 110 FERC ¶ 63,026 at P 38, 43 (2005).

[9] *Id.* at P 33-43.

[10] *Id.* at P 61.

[11] *Id.* at P 58.

[12] *Id.* at P 48.

ALJ said that "a bit more evidence" was presented to support the local component of the 27.1 percent allocation factor, but it suffered from similar deficiencies and was under-supported.[13] In this regard, as noted below, the ALJ disagreed with PG&E witness Bell's assertion that more recent data tend to confirm the earlier analysis.[14]

13. The ALJ found CoGen Associates witness James Ross' testimony more convincing, which found that PG&E's more recent data does not support charging the standby class differently from other rate classes. Mr. Ross contends that PG&E's adjustment is discriminatory because there is no historical coincident peak data to justify PG&E employing any adjustment that would significantly increase the revenue allocation of the standby class in this proceeding.[15] PG&E's probabilistic methodology based on the aggregate contract demand of all standby customers results in an allocation of $4,765,950 as the basis for their rates, as compared to CoGen Associates' cost allocation proposal based on the 12 coincident peak methodology of $1,095,726.[16]

14. The ALJ added that PG&E's proposal also conflicts with the Commission's preference for the 12 coincident peak methodology for rate design purposes.[17] Further, the ALJ noted that PG&E has not shown that its methodology follows the Commission's long-held general principle that cost responsibility should track cost causation.[18]

15. The ALJ found that PG&E's proposed methodology does little to take into account the extent to which scheduled outages of qualifying facilities' generating facilities can be usefully coordinated with scheduled outages of PG&E's facilities. Instead, the ALJ stated, PG&E's 27.1 percent allocation factor is based on the assumption that random outages by the standby class cause PG&E to incur costs, and excludes consideration of

---

[13] *Id.* at P 49-50.

[14] *Id.* at P 51-52.

[15] *Id.*

[16] *Id.* at P 54.

[17] *Id.* at P 54. The ALJ cites *Union Electric Co. v. FERC*, 890 F. 2d 1193, 1199 n.7 (D.C. Cir. 1989); *Missouri Utilities Co.*, 6 FERC ¶ 63,041 at 65,241-42 (1979), *affirmed in relevant part*, 10 FERC ¶ 61,297 at 61,600 (1980); *New England Power Pool,* 86 FERC ¶ 61,262 at 61,966 (1999).

[18] *Pacific Gas and Electric Co.,* 110 FERC ¶ 63,026 at P 53-54.

the high reliability of the standby class; as to the latter, its ability to schedule maintenance is taken into account only by PG&E's choice to focus its analysis on those times where maintenance is unlikely to be scheduled.[19] In contrast, the ALJ noted, under the 12 coincident peak methodology presented by Mr. Ross, the standby class will properly pay for their actual use should their unscheduled *or* scheduled outages fall at coincident peak times and, accordingly, they will have every incentive to coordinate their scheduled outages.[20]

16. The ALJ concluded that PG&E had not met its burden to prove that its particular proposed standby transmission rate design is just and reasonable. Therefore, the ALJ found that PG&E's proposed rate is unjust, unreasonable, and unduly discriminatory. The ALJ also found that the rate design advocated by Mr. Ross is appropriately supported by the record and that CoGen Associates' proposed rate of $0.16125/kW-mo should be adopted.[21]

## Briefs on Exceptions

17. On March 11, 2005, PG&E and Trial Staff each filed exceptions to the initial decision. They argue: (1) the ALJ erred in holding that PG&E's particular proposed standby transmission rate design is unjust, unreasonable, and unduly discriminatory; and (2) the ALJ erred in holding that the rate design advocated by CoGen Associates witness Ross was appropriately supported by the record and that CoGen Associates' rate of $0.16125/kW-month should be adopted.[22]

18. Trial Staff asserts that PG&E presented timely and relevant evidence that fully supported its allocation factors. Trial Staff also states that PG&E's rates for standby customers do not violate 18 C.F.R. § 292.305(c)(2)(2005) of the Commission's regulations. Further, Trial Staff argues that CoGen Associates' testimony[23] does not demonstrate that the 12 coincident peak methodology should be used to allocate standby

[19] *Id.* at P 59.

[20] *Id.* at P 60.

[21] *Id.* at P 62.

[22] PG&E Brief on Exceptions at 4; Trial Staff Brief on Exceptions at 9.

[23] Exh. CAC/EPUC-1R, Table 2.

costs and such methodology does not properly assign cost responsibility for the costs associated with standby transmission service.[24]

**<u>Brief Opposing Exceptions</u>**

19. On March 31, 2005, CoGen Associates filed a brief opposing PG&E's and Trial Staff's exceptions. CoGen Associates argue that cost causation is the guiding principle for cost allocation and that no evidence was presented by PG&E that shows it incurs costs to serve the standby customer class greater than the costs that class would be assigned using the 12 coincident peak methodology.[25] Further, CoGen Associates state that PG&E incurs transmission costs to serve the standby class in exactly the same way as it does to serve every other customer class, based on system peak usage.

20. CoGen Associates further argue that PG&E's particular contract demand allocation was not adequately supported. Specifically, CoGen Associates state that there is inadequate evidentiary support for the 12 percent factor for regional transmission costs and the evidence supporting the 38 percent factor for local transmission costs is outdated.[26] Furthermore, CoGen Associates state PG&E's allocation factor is not based on data demonstrating cost causation and fails to reflect any consideration of coordination of outages.[27] Thus, CoGen Associates assert that the ALJ's finding that PG&E's proposed 27.1 percent allocation factor is unjust and unreasonable should be affirmed.

**<u>Discussion</u>**

21. The remaining issue in this proceeding is whether the standby transmission rates proposed by PG&E have been shown to be just and reasonable. The briefs on and opposing exceptions raise these more specific issues: (1) does PG&E's use of a probabilistic analysis properly determine the cost responsibility of the standby customer class; (2) is there substantial evidence in the record to support PG&E's proposed rates for the standby customer class; (3) in contrast, does the 12 coincident peak cost allocation methodology proposed by CoGen Associates properly allocate costs to PG&E's standby

---

[24] Trial Staff Brief on Exceptions at 9-11.

[25] CoGen Associates Brief Opposing Exceptions at 3.

[26] *Id.* at 9-10.

[27] *Id.* at 13, 16.

customers; and (4) does PGE's proposed cost allocation to the standby customer class violate section 292.305(c)(2), and fail to reflect coordination of outages by the standby customers.

### A. Probabilistic Methodology for Standby Service

22. The ALJ found that: (1) PG&E has an obligation to provide standby service when it is called upon; (2) PG&E's proposed standby rate is not *per se* unreasonable or discriminatory merely because PG&E uses a 12 coincident peak methodology for other rate classes; (3) the standby customer class is not similarly situated to other customer classes; (4) a rate based on contract demand may be appropriate; and (5) PG&E standing ready to provide transmission service to standby customers on demand is a valuable service and rates based on this potential use of transmission, rather than actual use, are not *per se* unreasonable and may be reasonable if they are based on reasonable extrapolations from historical data on operating demand.

23. In addition, we note that PG&E has been charging standby rates to its standby customers since at least 1993, when the California Public Utilities Commission set the rates for service to the standby customers, employing Mr. Bell's probabilistic methodology,[28] and this technique was continued through the unbundling process when those charges were unbundled and energy charges were separated from transmission charges and the latter became the subject of PG&E's transmission owner rate cases before this Commission.[29]

[28] The use of a probabilistic methodology to charge cogenerators purchasing standby power had its origin in the Commission's rulemaking implementing rate-setting rules after the enactment of section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. § 824a-3 (2000), wherein the Commission indicated to the state commissions, who would be setting the rates for standby service for cogenerators, that "a qualifying facility is entitled to purchase back-up or standby power at a non-discriminatory rate which reflects the probability that the qualifying facility will or will not contribute to the need for and the use of the utility capacity." *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,887, 30,889 (1980).

[29] The first such case was filed in 1997. *See Pacific Gas and Electric Co.*, 81 FERC ¶ 61,323 (1997).

**Commission Decision**

24. No exceptions were filed by any participant to these findings and conclusions, and we will affirm the ALJ's findings and conclusions. Based on our review of the record and the ALJ's initial decision, we find the ALJ's findings and conclusions reasonable and supported by substantial evidence. In doing so we concur with the ALJ's view that PG&E's rate proposal need not be perfect but need only be reasonable.[30]

### B. PG&E's Evidence

25. The ALJ held that, while a rate design methodology based on a probabilistic analysis is permissible under these circumstances, PG&E has the burden to prove that its particular rate design is just and reasonable under section 205 of the FPA, 16 U.S.C. § 824d (2000).[31] The ALJ found that the main problem is with how PG&E calculated its 27.1 percent allocation factor.[32] However, rather than address the asserted deficiencies of PG&E's probabilistic methodology, the ALJ did not use a different probabilistic methodology or order a change to PG&E's 27.1 percent allocation factor, but instead adopted the 12 coincident peak methodology.[33]

26. Mr. Bell testified that PG&E's standby customers have unusual characteristics that are not shared by any other customer class.[34] Mr. Bell also noted that CoGen Associates witness Ross acknowledged that "the supply of standby service during periods of system coincident peak differs from full requirements service, because it is typically a function of random outages associated with customer generation equipment failure."[35] Mr. Bell also stated that PG&E must have adequate reserve capacity available to serve the loads of the standby class. Mr. Bell further testified that, in any given month, the standby class maximum demand might not, but also could, occur coincident with system peak.

[30] *Pacific Gas and Electric Co.*, 110 FERC ¶ 63,026 at P 31.

[31] *Id.* at P 38.

[32] *Id.* at P 58.

[33] *Id.* at P 51.

[34] Exh. PGE 45-2.

[35] *Id.*

27. Mr. Bell testified that PG&E has accounted for this uncertainty by using a statistical methodology to estimate what fraction of the total contract capacity should be treated as a reserve against the contingency of multiple, on-peak outages for customers' generation equipment.[36] PG&E's methodology provides that transmission costs be assigned to the standby class based on 27.1 percent of the total contract demand for the standby class.[37] According to Mr. Bell, the 27.1 percent cost allocation factor means that "in principle[,] . . . if I had 100 megawatts of standby demand, . . . I would attach 27 megawatts of cost responsibility to that 100 megawatts of standby demand, based on that allocation factor. . . ."[38] The 27.1 percent cost allocation factor was developed as a weighted average of:

> (1) a 12 percent allocation factor to be used for the purpose of allocating the *regional* transmission share (approximately 42 percent) of the total transmission revenue requirement; and
>
> (2) a 38 percent allocation factor to be used for the purpose of allocating the generally lower voltage, *local* transmission share (the remaining approximately 58 percent) of the total transmission revenue requirement.[39]

28. At the hearing, Mr. Bell was questioned about both the regional (12 percent) and the local (38 percent) components that formed the 27.1 percent cost allocation factor. For the 12 percent *regional* allocation component, he testified that the "12 percent factor came from a methodology that the CPUC…first adopted for assigning costs to standby contract capacity when it reviewed our standby rates in our 1993 general rate case." Mr. Bell stated that the "12 percent factor was originally developed as an allocation factor for generation cost[,]" but that he determined that it would be a reasonable

---

[36] *Id.*

[37] The standby customers as a class have contracted with PG&E for more than 600 megawatts (MW) of backup supply, and account for approximately 3.2 percent of PG&E's total customer load (on a MW basis). Thus, the prior TO5 settlement cost allocation factor assigned 0.87 percent (27.1 percent multiplied by 3.2 percent) of PG&E's total transmission revenue requirement to the standby transmission customer class.

[38] Tr. 202.

[39] In response to a Trial Staff Data Request, PG&E shows the determination of its 27.1 percent allocation factor: (12% x 0.418) + (38% x 0.582) = 27.132%. Exh. S-1.

reflection of *regional* transmission costs "[b]ased on the principle that regional transmission would be driven by system peak loads."

29. Mr. Bell explained that the 38 percent *local* allocation component was based on the ratio of "adjusted" standby customer demand to the total standby customer demand. Mr. Bell stated that he had not updated this methodology since it was used in PG&E's 1993 rate case. However, based on more recent load data, he testified that he does not believe that any fundamental changes have occurred and that the more recent data "tends to confirm the earlier analysis."

30. CoGen Associates witness Ross testified that PG&E's more recent historical data does not support charging the standby class differently from other rate groups. He details the standby class contribution to the average of PG&E's 12 monthly coincident peaks for 1997-2001. Mr. Ross states that, over this period, the average standby contribution to the 12 monthly coincident peak demands was only 0.17 percent. He further notes that the highest percentage, 0.24 percent, was in 2001, the year used by PG&E as a test year. Therefore, Mr. Ross contends that PG&E's "adjustment" is discriminatory because there is no historical coincident peak data to justify PG&E "employing any adjustment that would significantly increase the revenue allocation of standby in this proceeding."

31. The ALJ found Mr. Ross' testimony more convincing than Mr. Bell's as reflecting the more recent data and behavior of the standby class. The ALJ stated that the relatively small size of the standby class' contribution to the coincident peaks contrasts with Mr. Bell's assertion that an allocation based on the 27.1 percent standby cost allocation factor is reasonable. Further, the ALJ held that the reliance on a 1993 rate case produces an allocation that is at odds with more recent data and Mr. Bell has not explained the 27.1 percent factor in relation to these more recent numbers beyond asserting that the more recent data "tends to confirm the earlier analysis."

32. PG&E argues on exceptions that the ALJ erred in holding it did not provide support for the probabilistic analysis underlying its standby transmission rate design. Mr. Bell's testimony that he examined recent historical data and found it confirmed the analysis supports the analysis underlying PG&E's proposed standby transmission rate.[40]

33. PG&E states, that with regard to the 38 percent local component, Mr. Bell pointed to recent 2001 data showing that the single largest individual standby customer within

[40] Tr. 215-16.

each of the six zones typically accounts for between 29 and 48 percent of the total contracted standby load in that zone.[41]

34. PG&E also states that the ALJ erred because she relied on Mr. Ross' testimony which consists only of looking at the average of the 12 monthly coincident peaks, which is a simple average of the standby class demand over a year long period. This should be rejected, PG&E argues, because the transmission system must be capable of meeting the class demand even at the time of the system's peak usage. For example, the average of the 12 monthly coincident peaks produces a demand of 40 MW where the usage at or near coincident peak was 70-100 MW in certain months. PG&E argues that this usage level is consistent with the 12 percent regional component. PG&E argues that PG&E must be ready to provide service on demand, and so rates based on this potential use are reasonable when developed, as here, based on reasonable extrapolations from historical data. PG&E argues, that by accepting CoGen Associates simple averaging, the ALJ is not allowing recovery for costs associated with standing ready to serve fundamentally unpredictable loads.

35. Trial Staff agrees that PG&E presented timely and relevant evidence that fully supported its 27.1 percent allocation factor. Trial Staff notes that both the 12 and 38 percent components were established in testimony that Mr. Bell sponsored in a 1993 general rate case before the California Public Utilities Commission and these factors along with the proposed standby rate design were most recently used in the TO5 settlement in Docket No. ER01-66-000.[42]

36. Trial Staff argues that Mr. Bell was able to verify that there have not been any fundamental changes in PG&E's standby operations since the time of the 1993 study.[43] Trial Staff argues that, Mr. Bell confirmed, based on 2001 data, the continued appropriateness of the 12 percent regional cost component:

> . . . [E]ven the data that is presented in Mr. Ross' Table 3 (at page 13 of his testimony) shows that the 12 percent cost allocation factor that PG&E uses to assign costs at the regional transmission level is fairly conservative. The

---

[41] Exh. PGE-45 at 45-6 and 45-7.

[42] *See Pacific Gas and Electric Co.*, 96 FERC ¶ 61,122 (2001). The TO5 settlement, which was filed on June 8, 2001, explicitly sets forth the allocation factor in section 2.2(c).

[43] Tr. at 215-16.

> 12 percent factor, after being applied to 600 MW of contracted standby demand, provides cost recovery for somewhat less than an 80 MW share of regional transmission facilities. The table at page 13 of Mr. Ross' testimony shows that the maximum non-coincident peak demand of the standby class exceeded this level during five of the twelve calendar months of 2001 (in March, April, May, June, and October) and that at least two of these occurrences were during the weekday partial-peak time-of-use period March, May), and thus were at or near time when this level of standby usage would coincide with the system peak. [44]

37. Trial Staff argues that Mr. Bell also presents relevant and timely 2001 data concerning the 38 percent local component. Trial Staff notes that he states, "[d]ata providing additional support for the 38 percent cost allocation factor is presented in Table 1, attached to page 45-8 of this testimony, showing how PG&E's current standby customer population is distributed both by size and geographic location . . . ."[45] Trial Staff argues that PG&E witness Bell provides a full explanation as to how the current data reflected in Table 1 of his testimony updates and confirms the 38 percent local component.[46]

38. Trial Staff argues that a weighted average based on 2001 data shows that the average standby load for all six zones is 37 percent and thus is comparable to the data generated by PG&E for its 1993 probabilistic analysis, which yielded a 37.81 percent local component (rounded up to 38 percent).[47] Further, Trial Staff argues that PG&E

---

[44] Exh. PGE-45 at 5-6. Table 3 shows that the standby maximum non-coincident peak (NCP) demand was: (1) 150.8 MW in March, (2) 84.6 MW in April, (3) 91.9 MW in May, (4) 83.9 MW in June, and (5) 94 MW in October.

[45] *Id.* at 6.

[46] *Id*. at 6-7.

[47] Tr. 204-05; Exh. PGE-45 at 88.

supplied extensive underlying data[48] that compare patterns of loads and provide clear examples of the extreme variability and randomness of the standby loads. [49]

39. Trial Staff concludes that, contrary to the ALJ's suggestion that PG&E presented mere "assertions" to support its case, the data provided is extensive and clearly superior to that which was relied upon by the ALJ.

40. CoGen Associates respond that PG&E's calculation of the contract demand allocation was not adequately supported. It claims there is no support for the 12 percent regional component because it is not related to cost causation. CoGen Associates argue that the evidence supporting the 38 percent local component was outdated because it was developed in the 1993 study and not updated for intervening transmission tariff cases over the past ten years.

**Commission Decision**

41. Contrary to the ALJ's finding, we find substantial and persuasive evidence to support PG&E's proposed allocation of costs to the standby class of customers, *i.e.*, the use of the probabilistic methodology and the 27.1 percent allocation factor, and grant the exceptions to the initial decision.

42. There was no direct challenge to the appropriateness of the underlying probabilistic approach for allocating costs to the standby class of customers, as previously developed and approved in the CPUC rate case or the TO1-TO5 rate cases before this Commission. The only challenge stemmed from the essentially conclusory finding that this analysis is outdated. The fact that an analysis was originally developed

[48] The data supports Table 1 in Exhibit PGE-51, which contains three attachments that subset the loads for calendar year 2001 in different ways. Trial Staff contends that this 40-page exhibit provides very specific detailed numerical data that reflects: (1) all of the classes' loads by zone coincident with the system peaks; (2) all of the customer class loads by zone coincident with the monthly peak load for each separate zone; and (3) all of the customer class non-coincident maximum loads by zone.

[49] For example, Trial Staff states that Exhibit PGE-51, Attachment 002-12-1 shows that on June 21, 2001 at hour 17 (5 p.m.), the standby class had a coincident peak of 43.6 MW, which is much more than the 9 MW coincident peak on August 8, 2001 at hour 17 (*Id*. at 4), but significantly less than the 118 MW coincident peak on March 21, 2001 at hour 20 (8 p.m.) (*Id*. at 4).

for a 1993 rate case does not, by itself, mean that that analysis necessarily must be rejected—especially when that analysis has been carried forward through five rate proceedings at this Commission and supported by more recent data as outlined in our summary of PG&E’s and Trial Staff’s arguments and evidence above. In this regard, we note that no specific evidence was submitted to support using a probabilistic analysis with an allocation factor other than the 27.1 percent allocation factor PG&E proposes.

43. The ALJ asserted that there was insufficient support for the 12 percent regional transmission component. We disagree. The record reflects that, while the average of the 12 monthly coincident peaks produces a demand of 40 MW, the usage at or near coincident peak was 70-100 MW in certain months; this usage level is consistent with the 12 percent regional transmission component. Mr. Bell confirmed, based on 2001 data, the continued appropriateness of the 12 percent regional cost component:

> . . . [E]ven the data that is presented in Mr. Ross' Table 3 (at page 13 of his testimony) shows that the 12 percent cost allocation factor that PG&E uses to assign costs at the regional transmission level is fairly conservative. The 12 percent factor, after being applied to 600 MW of contracted standby demand, provides cost recovery for somewhat less than an 80 MW share of regional transmission facilities. The table at page 13 of Mr. Ross' testimony shows that the maximum non-coincident peak demand of the standby class exceeded this level during five of the twelve calendar months of 2001 (in March, April, May, June, and October) and that at least two of these occurrences were during the weekday partial-peak time-of-use period (March, May), and thus were at or near time when this level of standby usage would coincide with the system peak. [50]

44. The ALJ also decided that the 38 percent local transmission component was undersupported. After reviewing the evidence, we reach a different conclusion. Mr. Bell analyzed 2001 data and explains how that data updates and confirms the 38 percent local cost factor.[51] Mr. Bell explained that this 2001 data shows that the single largest individual standby customer within each of the six zones typically accounts for between

---

[50] Exh. PGE-45 at 5-6. Table 3 shows that the standby maximum non-coincident peak (NCP) demand was: (1) 150.8 MW in March, (2) 84.6 MW in April, (3) 91.9 MW in May, (4) 83.9 MW in June, and (5) 94 MW in October.

[51] Exh. PGE-45 at 6-7.

29 and 48 percent of the total contracted standby load in that zone.[52] These data are consistent with the use of a 38 percent local transmission component. Trial Staff explains with similar persuasiveness that, based on 2001 data, the average standby load for all six zones is 37 percent and thus is comparable to the data generated by PG&E for its original 1993 probabilistic analysis, which yielded a 37.81 local transmission allocation factor (rounded up to 38 percent).[53]

45. The ALJ instead placed more faith in the testimony of CoGen Associates witness Ross. However, we find that it contains nothing that would invalidate Mr. Bell's probabilistic analysis and his review of 2001 data other than the assertion that only a 12 coincident peak methodology is appropriate for designing the standby class rates.[54] As we discuss in succeeding sections of this order, we find that a 12 coincident peak methodology is not appropriate for the design of PG&E's standby class rates.

46. The fact that PG&E's proposed rates are higher than those proposed by CoGen Associates, *i.e.*, $4,765,950 for PG&E's rates, as compared to $1,095,726 for the CoGen Associates' rates, does not by itself justify rejecting PG&E's proposed rates. In fact, as explained above, the record supports PG&E's proposed 27.1 percent cost allocation factor and resulting rates.

47. Regarding the probabilistic analysis, CoGen Associates argued that consumption data of individual customers may have changed over the past 10 years; however, no evidence was adduced to support that view. To the contrary, we have found above that PG&E's 2001 data validates the prior analyses. Likewise, we find a customer-by-customer study unnecessary in view of Mr. Bell's analysis of the 2001 test year data by class and areas.

48. We add that there are other reasons supporting PG&E's proposed cost allocation and rates for standby transmission service. PG&E must stand ready to supply the entire 600 MW of contract demand at any time, including the system peak. A 27.1 percent allocation factor to allocate transmission costs to the standby customers is thus not on its face unreasonable. Further, the proposed rate is substantially less than the rate charged to full requirements customers who do not have their own generating capacity, and must

[52] Exh. PGE-45 at 45-6 and 45-7.

[53] Tr. 204-05; Exh. PGE-45 at 88.

[54] *See* Exh. CAC/EPUC 1R at 8.

rely entirely on PG&E's transmission system.[55] Finally, the 27.1 percent allocation factor is not inconsistent with the policy announced in our 1980 rulemaking, where the Commission stated that it expected that the rate to a qualifying facility should essentially reflect the degree of probability that the customer would need to take service from a utility.[56]

### C. 12 Coincident Peak Methodology and Cost Causation

#### (1) The 12 Coincident Peak Methodology

49. The 12 coincident peak methodology uses the average of the peak use from each of the 12 months in the test year to allocate costs to the customers. PG&E adopted this methodology for setting its rates for all services except for the standby customers.[57] The ALJ held that the 12 coincident peak methodology proposed by CoGen Associates properly allocates costs to PG&E's standby customers. PG&E and the Trial Staff filed exceptions to this finding.

50. According to the ALJ, "the Commission has previously adopted a demand charge calculated at coincident peaks in similar circumstances," [58] in particular in *Missouri Utilities*.[59] Trial Staff filed an exception, arguing that the ALJ's reliance on the *Missouri Utilities* case is misplaced. Trial Staff argues that case is clearly distinguishable on the facts. In *Missouri Utilities*, the Commission agreed that use of the 12 coincident peak methodology of cost allocation was appropriate to determine demand charges. In *Missouri Utilities*, there was a concern that, because the Cities were able to generate power during peak periods, the 12 coincident peak methodology would not accurately reflect their actual use of the system.

---

[55] Tr. 248-49.

[56] *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,889 (1980).

[57] Exh. PGE 45-3.

[58] *Pacific Gas and Electric Co.*, 110 FERC ¶ 63,026 at P 53.

[59] *Missouri Utilities Co.*, 6 FERC ¶ 63,041 at 65,241-42 (1979), *affirmed in relevant part*, 10 FERC ¶ 61,297 at 61,600 (1980).

51. Trial Staff argues that that case does not present circumstances similar to those at issue here, as the Cities in that situation had the ability to decide whether they would take service from Missouri Utilities or generate power from their own generating facilities. Trial Staff claims that that is substantially different from the standby service offered by PG&E. Trial Staff argues that the standby service that PG&E offers does not depend on whether or not the customers *choose* to generate power on their own, but rather on whether they *need* to draw electrical power from the transmission grid in the event of an outage of their generators. Trial Staff argues that it was precisely the unpredictability of the timing of these outages that led the ALJ to conclude that PG&E's standby customer class is not similarly situated to PG&E's other rate classes, which we have affirmed.

52. CoGen Associates argue that the ALJ properly relied on *Missouri Utilities* to establish a Commission preference for use of a 12 coincident peak methodology in a case similar to this one. CoGen Associates assert that in *Missouri Utilities,* the Cities, *i.e.,* the customers, argued that they were interruptible customers who could operate their own generation at the time of system peaks and the coincident peak methodology should be modified by subtracting from the coincident peak the capacity of their generation, which the Commission rejected in favor of the use of the 12 coincident peak methodology. CoGen Associates argue that similarly in this case it is the standby customers' actual demand which PG&E must provide transmission capacity to serve, not a contract demand, and so the Commission here should order the use of a 12 coincident peak methodology.

**Commission Decision**

53. We hold that the ALJ erred in ruling that *Missouri Utilities* supports the application of a 12 coincident peak methodology for rates to PG&E's standby customer class. First, the facts are distinguishable. The standby customers here are just that, standby, rather than essentially partial requirements customers as was the case in *Missouri Utilities.* In addition, the Commission effectively overruled *Missouri Utilities* when it announced, in *Central Power & Light Co.* in 1989,[60] its approval of billing partial requirements customers on a contract basis rather than on a usage basis.

[60] *Central Power & Light Co.,* 47 FERC ¶ 61,339, *rehearing denied,* 49 FERC ¶ 61,002 (1989).

54. Application of *Missouri Utilities* in these circumstances would also be inconsistent with our policy expressed in Order No. 888, which provides for billing on a reservation of capacity basis.[61]

55. Furthermore, in *Missouri Utilities*, a probabilistic analysis of the Cities' use of peak capacity was not before us and thus not considered by the Commission.

56. Although the Commission has frequently used the 12 coincident peak methodology in allocating costs, it does not hesitate to use a different methodology when appropriate,[62] such as in PG&E's TO1-T05 rate cases. Indeed, the Commission has never

---

[61] In Order No. 888, the Commission stated, with respect to point-to-point transmission service:

> The flexibility and reassignment rights of this transmission service require the transmission provider to hold the firm contract capacity available regardless of the customer's load characteristics or its actual use. In other words, a transmission provider's obligation to plan for, and its ability to use, a transmission customer's reserved capacity is clearly defined by that customer's contract reservation. For that reason, it is appropriate to consider a firm reservation as the equivalent of a load for cost allocation and planning purposes.

*Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No.888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 at 31,738 (1996), *order on reh'g*, Order No. 888-A, 62 Fed. Reg. 12,274 (March 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part, remanded in part on other grounds sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[62] *PacifiCorp*, 79 FERC ¶ 63,003 at 65,017 (1997), *affirmed*, 84 FERC ¶ 61,303 (1998).

endorsed any single cost allocation methodology for application in all circumstances and the Commission is not obligated to use the coincident peak methodology in all cases.[63]

57. Accordingly, exceptions to the ALJ's interpretation of the *Missouri Utilities* decision and the application of the 12 coincident peak methodology to PG&E's standby customer class are granted.

**(2) <u>Cost Causation</u>**

58. The ALJ also found that CoGen Associates' proposed 12 coincident peak methodology properly aligns cost responsibility with cost causation.

59. PG&E filed an exception arguing that CoGen Associates' proposed methodology does not account for the fundamentally random nature of the demand of the standby customer class and PG&E's obligation to stand ready to serve that demand.

60. Trial Staff argues that the 12 coincident peak methodology does not properly assign cost responsibility for PG&E's standby service. To the contrary, Trial Staff asserts that the use of a 12 coincident peak methodology would result in an under-assignment of costs to the standby class relative to what is fair and reasonable. As proposed by CoGen Associates, the standby customers would enjoy the right to receive transmission service for over 600 MW of service while paying no more than a 40 MW customer.[64] Trial Staff adds that Exhibit PGE-51 demonstrates that standby demand has been in fact much higher than 40 MW.[65]

---

[63] *See, e.g., American Electric Power Service Corp.*, 44 FERC ¶ 61,206 at 61,749, *rehearing denied*, 45 FERC ¶ 61,408 (1988), *rehearing denied*, 46 FERC ¶ 61,382 (1989).

[64] Exh. PGE-45 at 4-5.

[65] For example, on March 21, 2001 at hour 20 (8 p.m.), at the time of the system's coincident peak, standby service coincident peak was 118 MW. In another instance, on August 29, 2001 at Noon, the standby maximum demand for Zone B alone was 42 MW. On September 6, 2001, at hour 10 (10 a.m.), the standby load was 123 MW for just Zone B and on October 17, 2001 at hour 9 (9 a.m.) the standby load for Zone B was 108 MW. *See* Exh. PGE-51, Attachment 002-12-1 at 4 and Attachment 002-12-3 at 8.

61. Trial Staff argues that there is a cost associated with standing ready to serve PG&E's standby customers that is not accurately reflected in merely comparing the standby customers' average actual demand to the average of the system's 12 monthly coincident peak demands. Trial Staff argues that PG&E's methodology more accurately reflects the reserve capacity needed (and the costs incurred) for PG&E to satisfy its obligation to stand ready to serve these customers.

62. CoGen Associates argue that the issue is whether PG&E's different treatment of the standby class accurately reflects that class' cost causation, given that cost causation is the principle by which costs should be allocated to classes. They argue that the evidence establishes that the utility incurs transmission costs to serve the standby class in exactly the same way as it does to serve every other class, *i.e.,* based on system peak usage, and the 12 coincident peak methodology accurately allocates costs to all classes.[66] CoGen Associates argue that the coincident demand for transmission capacity determines each class' relative cost causation.

**Commission Decision**

63. In considering the matter of cost causation, the courts have stated that "it has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them."[67] We have found that there is a cost incurred, however, in having PG&E standing by to provide up to 600 MW of transmission service that may be imposed by the standby customers. We have concluded above that PG&E's probabilistic methodology fairly allocates the costs of PG&E's transmission system to the standby class, and is supported by substantial evidence. This methodology appropriately provides the necessary nexus between costs incurred and rate responsibility.

64. On the other hand, we have found that the 12 coincident peak methodology is inappropriate for allocating costs to the standby class of customers, for the reasons set out above. The 12 coincident peak methodology used to allocate costs to other classes of

---

[66] CoGen Associates refer to the testimony of PG&E's witness Ben Morris who testified that the transmission system is constructed to meet the annual system peak, based on the adequacy of the regional 500 kV system and the lower voltage zonal system area peaks. Tr. 269, 271.

[67] *KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992).

customers does not fairly allocate costs to the standby class of customers when, on this record, we have found that the standby class of customers is not similarly situated with PG&E's other classes of customers because of their unpredictability and demand for service from PG&E only when their own generators are unable to supply their own needs.

65. Accordingly, we conclude that our decision on the proper cost allocation for, and the rates charged to, the standby class of customers reasonably reflects the costs imposed by the standby customer class, and the rates proposed by PG&E are just and reasonable.

### D. Section 292.305(c) Issues

66. This proceeding involves two issues with respect to section 292.305 of the Commission's regulations. Section 292.305(c) states that:

> The rate for sales of back-up power or maintenance power:
>
> (1) Shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and
>
> (2) Shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

67. CoGen Associates argued that PG&E's rate methodology violates section 292.305(c)(1).[68] CoGen Associates argued that PG&E's methodology assumes that outages "that actually occurred at other times are occurring on the system peak, which is the relevant point in time for determining cost responsibility."[69]

68. The ALJ disagreed, as PG&E does not assume that all cogeneration facilities will experience forced outages at once or at system peak. Instead, the ALJ held that PG&E accounts for the possibility that some outages could randomly occur at any time, including system peak, and so does not violate section 292.305(c)(1). No exceptions

[68] *Pacific Gas and Electric Co.,* 110 FERC ¶ 63,026 at P 56.

[69] *Id.*

were filed to this finding.

69. However, the ALJ also held that while PG&E's methodology for developing its 27.1 percent allocation factor does not violate section 292.305(c)(1), PG&E's proposal does not comply with section 292.305(c)(2). The ALJ found that Mr. Bell's methodology is based on outages at times "between 8:30 and 9:30 which corresponds to the summer on peak and part peak periods," which Mr. Bell claims gave him "a pretty high degree of confidence that we're focusing entirely on backup power and not on maintenance power." The ALJ believed that this focus on time periods that Mr. Bell believes represent unscheduled outages shows that PG&E has excluded consideration of scheduled outages from its formula to a large degree, and concluded that Mr. Bell's methodology does little to take into account the extent to which the standby customers' scheduled outages of qualifying facilities can be usefully coordinated with PG&E's scheduled outages.[70]

70. PG&E argues that its cost allocation for the standby class reasonably and appropriately focused on costs associated with unscheduled outages and excepted to the ALJ's findings. PG&E points to Mr. Bell's testimony that his cost allocation focused exclusively on those periods when standby service is extremely unlikely to be caused by scheduled outages.[71] PG&E argues that, given that its probabilistic analysis is focused on periods when all standby usage can reasonably be assumed to be caused by unscheduled generator outages, PG&E's rate design assigns costs to the standby class implicitly assuming that all scheduled outages will already be usefully coordinated with its own scheduled outages based on the assumption that maintenance outages are scheduled outside of the summer peak and is borne out by the load data; its cost allocation analysis meets the regulation's requirement by excluding all likely scheduled maintenance usage from load information that PG&E uses to develop the standby service allocation factors. Furthermore, PG&E argues this results from the strong economic incentives to schedule maintenance outages derived from the provisions of the standby service contracts with the utility.[72] PG&E concludes that the ALJ erred in finding that its methodology excluded consideration of scheduled outages.

71. Trial Staff argues that PG&E's rates for standby customer do not violate section 292.305(c)(2) and the ALJ erroneously found difficulties with PG&E's rate design; the high reliability of the standby class and its ability to schedule maintenance are already taken into account by PG&E's choice to focus on times where maintenance is unlikely to

[70] *Id.* at P 55-59.

[71] Tr. 211, 234-35.

[72] Tr. 259-60.

be scheduled.

72. Trial Staff argues that PG&E's rate structure for standby service makes it more advantageous for standby customers to schedule outages at times other than when the system coincident peak is likely to occur. Trial Staff notes that this was acknowledged not only by PG&E witness Bell, but also by CoGen Associates witness Ross.[73] Trial Staff argues that PG&E's 43 cents/kWh rate for standby peak summer service is substantially higher compared to its partial peak summer rate of 9.5 cents/kWh, the partial peak winter rate of 10.7 cents/kWh, and the off-peak winter rate of 7.9 cents/kWh, and that maintenance power would not be expected to contribute to the coincident peak of the system.[74]

73. CoGen Associates respond that PG&E fails to reflect any consideration of coordinating outages in its allocation factor. CoGen Associates contend that PG&E's methodology fails to comply with section 292.305(c)(2) and provides no incentive for coordinating outages.

**Commission Decision**

74. With regard to section 292.305(c)(1), CoGen Associates did not file an exception to the ALJ's finding. With regard to section 292.305(c)(2), we find that PG&E has satisfied the regulation. We base our finding on the evidence in the record that standby rates were based on summer months' usage of standby power, which would not likely include maintenance power required by the standby class; Mr. Bell explained these circumstances in response to the ALJ's inquiry during the hearing.[75]

75. CoGen Associates also argue that PG&E's methodology provides no incentives for coordinating outages. Mr. Bell testified, however, that PG&E's rate structure for the standby class, in fact, provides an incentive to standby customers to take maintenance power at some time other than a peak period. Furthermore, there is an even stronger incentive to do so if they are a standby customer that sells power into the markets, as most standby customers do, as they get paid the most for their power production during the peak and part-peak summer periods.[76] Accordingly, we reject CoGen Associates' argument regarding incentives for coordinating outages.

[73] Tr. 211; Exh. CAC/EPUC-1R at 4.

[74] Exh. CAC/EPUC-1R at 4.

[75] Tr. 234-35.

[76] Tr. 211-12.

76. Finally, we add that section 292.305(c)(2) only requires coordination of scheduled outages be considered in setting rates to the extent that it is feasible to do so. We believe the record reflects that rate setting for transmission rates to the standby customer class is unaffected by scheduling of maintenance power by the standby class. CoGen Associates witness Ross concurred with this view in his testimony that "the 'maintenance power' provided under PG&E's standby rate would not be expected to contribute to the coincident peak of the system."[77] Accordingly, no adjustment to the standby rates is required under these circumstances.

<u>The Commission orders</u>:

The Initial Decision is hereby affirmed, reversed, and modified as discussed in the body of this order.

By the Commission.

( S E A L )

Magalie R. Salas,
Secretary.

[77] Exh. CAC/EPUC-1R at 4.